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A comparative review of modelling and controlling torsional vibrations and experimentation using laboratory setups

Parimal Arjun Patil *, Catalin Teodoriu

Institute of Petroleum Engineering, Clausthal University of Technology, Agricola Str. 10, Clausthal-Zellerfeld, Niedersachen 38678, Germany

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ABSTRACT

Improved drilling performance enables us to drill a high quality well at less cost per foot in the lowest time possible. Drillstring vibration is one of the limiting factors maximizing drilling performance. Also, it has become necessary for drilling oil/gas/geothermal wells in order to optimize surface drilling parameters and to reduce downhole dynamics while drilling. Operating a drillstring above or below the critical speed will definitely reduce vibrations and the probability of premature catastrophic failure of downhole components. Hence, it is necessary to carry out pre-drilling analysis as well as real time analysis of drillstring dynamics.

The complexity of the drilling phenomenon makes it impractical to derive models having worldwide acceptability. Modeling the entire drillstring system and validating the results using the laboratory experiments or the field data have been the best practice. Most of the times, the parameters affecting the model's sensitivity are either unknown or insufficiently studied during the modeling which makes the study more challenging. The first part of the current review article summarizes the work carried out by the researcher in the field of modeling and controlling torsional vibrations. The second part highlights the experimental studies carried out in laboratories in order to reproduce modes of vibrations in the laboratory. Based on the past development, further efforts can be outlined in this field in order to improve the quality of reproduction of torsional vibrations in the laboratory. The present article reviews the information which needs to be considered while modeling a complete drilling system and developing a laboratory model to reproduce torsional vibrations.

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1. Introduction

Drillstring is under dynamic loading while drilling a hole which results in vibration. Vibration is defined as a to and fro movement which is the manifestation of the oscillatory behavior in the drillstring. Drillstring has its own mass, certain stiffness and dynamic forces acting while in process. Combination of mass, stiffness and dynamic forces lead the system to vibrate. Vibrations are unavoidable since drilling is the destructive process of cutting rock either by chipping (using drag/PDC bits) or crushing (using roller cone bits) action. Field observations have shown difference in vibration measurements on surface and in downhole which means BHA undergoes severe vibrations. Nonlinear interaction between bit/formation and drillstring/borehole results in vibration acting as an excitation source. Drillstring vibrates in three basic modes/directions: axial, lateral and torsional. When the drillstring

* Corresponding author. Tel.: +49 5323 722889; fax: +49 5323 723146.
E-mail address: parimal.patil@tu-clausthal.de (P.A. Patil).

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moves along its axis of rotation it is called axial vibration. Lateral vibrations are caused when the drillstring moves laterally to its axis of rotation. Torsional vibrations are caused due to an irregular rotation of the drillstring when rotated from the surface at constant speed and mostly observed while drilling with drag bits. In reality, drillstring vibrates more often as combinations of all these three basic modes which make the problem fairly complex to measure and investigate. Drillstring vibration will generate frequency noise which adds to the downhole measured data leading to a dramatic deterioration of the transmitted data. It is possible to avoid critical torsional and lateral resonance by simply adjusting manually the weight on bit (WOB) and rotations per minute (RPM) at the surface. Vibration prediction programs are also available, mostly offline, which can estimate critical RPMs for a given drilling assembly. Controlling drillstring dynamics has been a challenge in oil industry from past many years. Complex interaction between bit, drillstring and formation has been solved analytically as well as mathematically and many mathematical models are also available. Control algorithms are available in order to eliminate vibrations using the torque feedback system but the proper tuning of the controller on the surface has been identified as a critical issue. Following part of this study presents the research carried out on modeling and controlling of torsional drilling vibrations as well as attempts made to validate the models using laboratory based experimental setups.

2. Studies on modeling and controlling of torsional drillstring vibrations

Very first problem was tackled by developing dynamic models and verifying it with experimental study of the drillstring by Bailey and Finnie (1960) and Finnie and Bailey (1960). Aarrestad et al. (1986) worked extensively on understanding and mitigating vibration both by developing mathematical models as well as verifying them with experimental results but with limited insight and have claimed that axial vibration at the top of the drillstring depends on damping along the drillstring and frequency of the excitation. According to Halsey et al. (1986), the lowest torsional frequency is very sensitive to properties of drill pipes and drill collars, and these frequencies are independent of rotations per minutes, weight on bit and damping effect, as long as the drillstring rotates freely while the drillstring undergoes friction along the wellbore. Dawson et al. (1987) has observed during drilling that the torque at the top drive fluctuates with time which is caused due to interruption of downhole tool rotation and is irregular because of the downhole friction factor. It was proposed by Dawson et al. (1987) that a reduction in the static friction is a possible solution to the stick–slip problem. Stick–slip situation occurs when the static friction coefficient is sufficiently high enough than the dynamic friction coefficient. As drillstring is rotated continuously on surface, it stores torsional energy. When this torsional energy exceeds static friction, the bit accelerates and rotates with maximum speed and unwinds the drillstring. This phenomenon is called stick–slip and can generate self excited vibrations. Stick–slip condition was mathematically modeled by Halsey et al. (1988) by assuming the drillstring behaves like a simple torsional pendulum with one degree of freedom. The model could not predict occurrence of stick–slip under given sets of conditions. It was seen in model that with the increase in rotary speed, there was a decrease in mean torque value, which was not explained by the theory presented by Kyllingstad and Halsey (1988).

The model developed by Apostal et al. (1990) considered damping in FEM based forced-frequency response models due to the presence of fluid, formation, friction and other effects. In addition, viscous and structural damping mechanisms were also considered. Having capability for computation of damping and added mass effects within the program, it assumes cyclic behavior of drillstring which is not a real situation downhole. Spanos and Payne (1992) worked extensively on the complex dynamic behavior of drillstring using frequency response models. These models were unable to reproduce the observed dynamic phenomenon, though it provides qualitative analysis of BHA performance. According to the sensitivity analysis by Spanos and Payne (1992), understanding the critical BHA dynamic factors include (a) damping which plays an important role in controlling response at excitation, (b) drilling fluid density which alters the natural frequencies of BHA elements, and (c) effect of weight on bit on the system. The model also does not consider stiffness of components, excitation frequency of every BHA element, and mainly the experimental analysis. Brett (1992) presented a model which showed that the bit–rock interaction initiates the torsional vibration in the system and could be eliminated by controlling gain in surface rotary system. Simple model uses two differential equations that were solved using the Runge–Kutta simulation approach. Models developed consider the behavior of drillstring as a lumped mass with spring and the surface drive system, see Fig. 1. It assumes the standard relationship: (a) drill pipe stiffness and the rotational inertial, and (b) constant drillstring friction torque and laboratory drilling data, for the relationship between bit torque and rotary speed. The model also describes that the bit induced torsional vibration could be eliminated by overrunning the motor which was not field tested.

Dunayevsky et al. (1993) studied drillstring dynamics as a function of drilling parameters. The finite element model (FEM) was developed which considered continuous wall contact. With the developed parametric resonance model, it was possible to indicate the mode of failure but it lacked the behavior of failure with respect to time. It does not consider the effect of whirl and stick–slip. Dykstra et al. (1994) evaluated interaction of drill bits and different types of formation extensively by performing laboratory and field experiments recommending operational deficiencies in order to reduce the downhole vibration. Further work by Dykstra et al. (1996) presents numerical modeling which shows

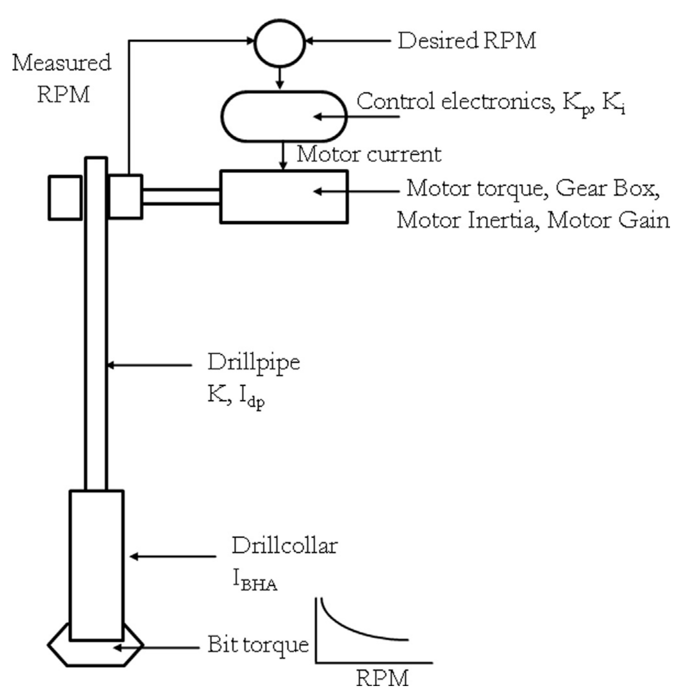

Fig. 1. System diagram showing parameters considered for modeling (Brett, 1992).